Integrated hydrological, power system and economic modelling of climate impacts on electricity demand and cost

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Abstract

Previous studies have failed to capture critical dynamics within overlapping hydrological, power, and economic networks when assessing the economic impacts of future water stress on the power system. In this paper, we employ a coupled water-power-economy model to capture these important interactions in a study of the exceedance of water temperature thresholds for power generation in the Western U.S. We identify three key determinants of economic impacts – thresholds, teleconnections, and timing. We find that not all reductions in reserve electricity generation capacity result in impacts (thresholds), and that when they occur, intermittent interruptions in electricity supply at critical times of the day, week, and year account for much of the economic impacts (timing). Lastly, we find that impacts may be in different locations from the original water stress (teleconnections). Decomposing the relative importance of these three determinants of economic impacts would not be possible without a coupled modeling approach that captures interactions across systems while retaining spatial, temporal, and sectoral detail.

As evidence of a changing climate grows, managers of critical infrastructures are increasingly seeking ways to improve the resilience of these systems. Energy systems, especially the electric power system, are vulnerable to natural stressors associated with a changing climate, such as wildfires, severe storms, extreme temperatures, and long-term disruptions of the hydrological cycle. For example, chronic water shortages in the Western U.S. have gone unabated, and an increased frequency and severity of droughts and heat waves could result in insufficient cooling water for thermal generators, restricting power supply. Effective planning and management of the energy infrastructure requires quantifying the magnitude of the impacts from hydrological changes and higher temperatures and identifying where and when these impacts may occur.

As a motivating case study, we focus on the impacts on the electric power supply of the exceedance of water temperature thresholds for thermal generation because of reduced water flows in the Western U.S., how supply outages translate to demand interruptions, and the consequent economic impacts of the demand interruptions. The innovation of this study is the representation of the causal linkages from water stress-induced generator outages to curtailed electricity demand elsewhere, and in using the chronological hourly profile of demand interruptions to determine productivity losses in economic sectors.

Previous studies have estimated the reductions in generation capacity that could result from water stress and increased temperatures.[1,2,3,4] This reduction in the capacity reserve margin, the

potential supply of power if needed, is one critical link in the causal chain. Others have estimated the effect on the broader economy from electricity demand that cannot be met because of a supply disruption.[5,6,7] These studies have shown that the economic costs depend not on the average or aggregate amount of unmet electricity demand but on the specific temporal and spatial pattern of discrete outage events: the number of events, their duration, and the magnitude of each. The high-voltage transmission network is a century-old solution to increase resilience by moving power over long distances. A consequence of the grid is that supply shortages in one location may result in unmet demand in a different location.

Multisector dynamical systems, such as the coupled water-power-economy system in this study, are composed of overlapping and intersecting networks. The regional network of watersheds and basins is one layer. In the same geographic region, the electric power grid is another layer. The regional economy forms a third layer. The water and power networks intersect where generators draw water for cooling and use water for hydropower. The electricity transmission network then transfers energy from generators to demand centers. Economic sectors, such as manufacturing, use the electricity to produce goods and services for consumption. An external shock, such as higher temperatures or water scarcity, is transformed and transported through these interconnected networks, which may dampen or amplify the impacts in the process. In the absence of explicit analysis, it is difficult to predict how a shock will be translated through the interconnected networks and where the most significant impact will occur.

No prior study to the authors' knowledge has propagated climate forcing scenarios through water and power systems models with hourly resolution in the power grid to estimate unmet electricity demand. We build on previous efforts by quantifying the potential economic losses from a set of climate forcing scenarios, applying a multisector dynamic modeling framework that integrates a hydrological model, a detailed power system model with high spatial and temporal resolution, and a state-level economy-wide model of the U.S. We present a case study for the Western U.S. based on the Western Electricity Coordinating Council (WECC) reliability system. This corresponds to the twelve U.S. states west of the Rocky Mountains as well as portions of British Columbia, Alberta, and northern Mexico. We estimate the regional economic and sectoral productivity losses from a sample set of plausible one-year hydrological scenarios and we quantify the impacts that result from both the increased cost of electricity, and the lost productivity from unmet electricity demand. Finally, we distinguish between the direct impact of water temperature stress on the power system, and the impact after accounting for economic adjustment in response to the higher energy costs.

Our primary contribution is methodological: a coupled model framework that captures interactions across water, power, and economic systems while retaining spatial, temporal, and sectoral detail. In addition, we contribute three insights to the existing literature on this topic. First, we demonstrate that reductions in reserve capacity, power plants that are unavailable because of cooling water restrictions, may or may not result in actual physical and economic impacts (thresholds). Second, when economic losses do occur, the largest effects are from intermittent periods of electricity demand that cannot be fully met, while the higher cost of electricity has a smaller effect (timing). Third, the locations where impacts are experienced may

be geographically distant from the location of the water stress and may be the result of bottlenecks at some other locations in between (teleconnections).

Capacity outages from increased water temperatures

Our coupled model framework consists of the Water Balance Model (WBM), a spatially distributed hydrological model, the Power System Model (PSM) with chronological hourly resolution, and the Regional Economic Model (REM), a state-level computable general equilibrium model (See Methods and SI). We develop scenarios of future hydrological conditions, each representing a single year. We use downscaled projections from GFDL-CM3 and CCSM4 to provide boundary conditions. The WBM performs a dynamic simulation of daily water flows for 2006-2099 and use the results from 2041-2099 to construct scenarios. The PSM-REM coupled model simulates a single hypothetical future year and does not represent dynamics across years. We therefore treat each year of WBM output as a distinct plausible future scenario of water temperatures over a one-year period.

We identify 488 of the existing power plants in WECC that require water for cooling, and their geographic locations were mapped to grid cells within WBM and matched to the network location in PSM. To determine generator outages from hydrological conditions, we trigger an outage for any generator that uses water from cooling at a location where the water temperature exceeds the U.S. federal standard temperature threshold of 32 °C.[2,8,9] We focus on water temperature because it integrates the impacts of increased surface temperatures and reduced water volumes, and because the regulatory threshold is well defined. The one-year hydrological scenarios from WBM provide daily water temperatures at each power plant location, from which daily generator outages are determined.

There are many possible ways to aggregate the hourly outages of 488 generators over the entire year for one scenario. In the Supplemental Information (SI), we show the generation capacity outages for each of 118 one-year hydrological scenarios in terms of the number of hours of the year that one or more generators were unavailable because the water temperature threshold was reached and by the average total capacity unavailable for those hours with non-zero capacity outage. These scenarios result in capacity reductions ranging from 0 to over 12 GW of generation capacity for durations ranging from 0 to 3312 hours within a year. These results correspond to the capacity reserve reductions estimated in prior studies.[1,2,3,4]

When simulating a given one-year scenario, the daily generation outages resulting from the WBM water temperatures are imposed in the PSM, which solves for the hourly dispatch over the year. We find that among the 118 scenarios, those with average capacity outages of 2200 MW or less and/or occurring for 1400 or fewer hours of the year do not result in any meaningful changes in the cost of electricity relative to the base case nor in any unmet electricity demand (Figure S4 in SI). This is an example of a critical threshold in the coupled system. Many regions of the U.S. have excess generating capacity because of the legacy effects from traditional utility cost regulation and from reliability standards.[10] An important implication of this result is that a reduction in available generation capacity on a given day does not necessarily indicate any significant cost.

Impacts on power system from increased water temperatures

We use Importance Sampling (see Section SI.3) to select a set of 18 scenarios that induce non-zero impacts from water temperature stress and focus on these for the remainder of the analysis. We first present the potential impacts of each scenario by showing results from the first iteration of the PSM, before any economic adjustment has occurred. For each scenario, we solve the PSM for the 8736 hours of the year, excluding any offline generators from the water temperature constraint in each hour, and obtain the hourly output of each generator at each location in the network, the prices at each location, and whether any portion of electricity demand was not met in each hour at each location. The shadow prices from the optimization model on the supply-demand balance constraint at each of the 312 buses (nodes in the electrical network) in each hour represent the marginal cost of electricity.

Power system impacts on the hourly time scale must be aggregated to annual impacts to enable feedbacks with the economic model. We average the marginal costs over all buses in each hour and average these values over the year to obtain an annual average of the marginal cost. Note that the marginal costs are not only used as prices in wholesale electricity markets, but when average annual costs are higher, these will eventually be reflected in electricity rates in regulated regions. One effect of having some generators unavailable, which are often lower marginal cost units, is an increase in the generation cost in those hours. In **Figure 1a**, we show the increase in the marginal cost of electricity relative to the baseline (no water temperature-induced capacity outages) that results from the capacity outage patterns induced by each hydrological sample. Each point in the scatterplot represents a one-year simulation of the PSM for one annual sample of the daily spatial distribution of water temperatures. If there were no economic adjustment, the annual average increase in electricity cost would range from less than 1% to nearly 7%, depending on the water temperature scenario.

In addition to the increased cost of electricity, another major concern about water impacts on the power system is the inability to meet all electricity demand at every location in every hour of the year. Estimation of the spatial and temporal pattern of any unmet electricity demand requires a model that explicitly represents the transmission network, the chronological hourly demand, and inter-temporal constraints on generators, which cannot turn on or off instantaneously. In **Figure 1b**, we present the total unmet electricity demand in MWh for each scenario, summed over all network locations and all hours of the year. The amount of total unmet demand ranges from zero to over 50 GWh across these 18 scenarios.

We observe that for samples with relatively similar average capacity outage amounts in the 9 to 11 GW range, there is considerable variation in the amount of unmet demand. The scenarios differ in terms of the distribution of outage capacity, the particular locations impacted, and the particular days and times of day when outages occur. In general, the impact of outages should depend on the level of demand and on the location within the network. This is an example of the importance of timing in determining the impacts of different shocks to the system. Although the number of scenarios is not enough to be conclusive, these results are suggestive that the average quantity of outages may not be sufficient for estimating the consequences.

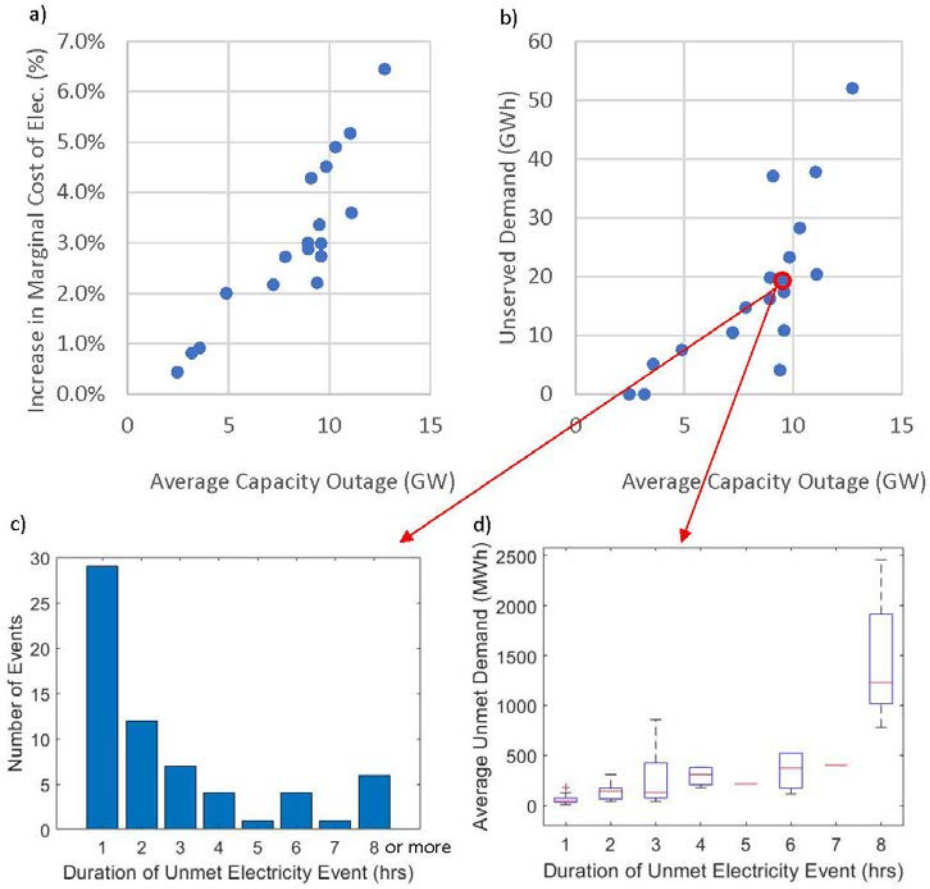

Figure 1*: Average capacity outage (MW) from 18 annual hydrological samples and the resulting a) increase in the annual average of the marginal cost of electricity ($/MWh) and b) annual total of unmet electricity demand (MWh). The distribution of the discrete chronological unmet demand events is shown for one sample (GFDL-CM3, year 2089) in c) as the histogram of the duration of each event and d) the range of the average magnitude of all events of each duration length.*

The total annual unmet demand for each water temperature scenario is the sum of unmet demand over all hours and locations, which aggregates a spatial and temporal pattern of discrete events. These events vary in duration, magnitude, and location. We show the distribution of unmet demand events for one annual hydrological sample, (GFDL-CM3, year 2089; circled in **Figure 1b**), in terms of the number of events of different durations in hours (**Figure 1c**) and the distribution of the average per-event magnitude of the unmet demand for all events of each duration as box-and-whisker plots (**Figure 1d**).

Impacts from power on economic activity without adjustment

Higher electricity costs and unmet electricity demand estimated from the PSM are propagated through the REM to estimate resultant losses to the economy. The REM captures the response of consumers and producers to the increases in the annual cost of electricity (from **Figure 1a**). To measure the productivity losses from unmet electricity demand, we build on prior work[6] which provides electricity customer interruption costs from a survey of ~12,000 U.S. firms and ~8,000 U.S. households. We use the firm-level interruption costs developed in Sullivan et al.,[6] which

vary by economic sector, season, day of week, time of day, and duration of outage, and apply these to the temporal pattern of unmet demand events over all hours in each scenario. The resulting sum of aggregate losses for each sector is then represented as a productivity loss for that sector in the REM. A useful metric of economic loss is the reduction in total final consumption, which we present in **Figure 2** for the importance sampling subset of 18 scenarios.

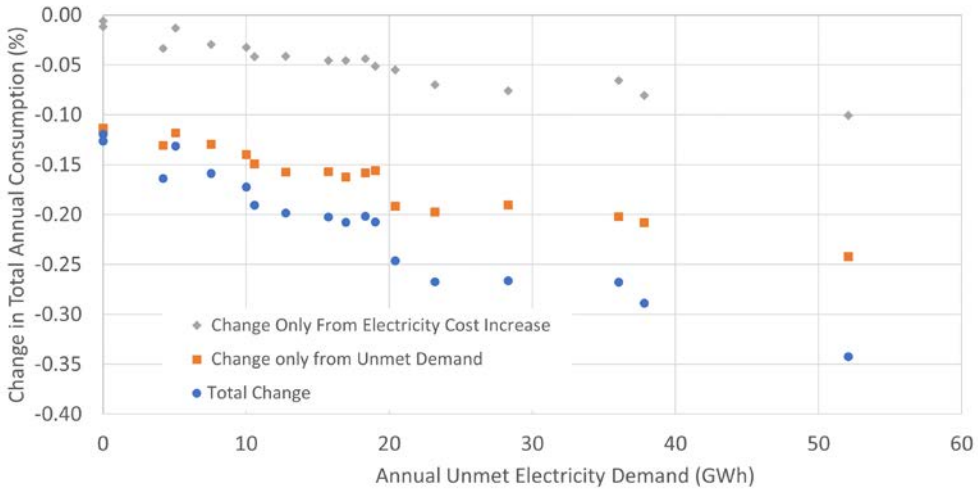

***Figure 2**: Consumption loss (%) resulting from unmet electricity demand, increase in electricity cost, and the total loss from both effects. Each scenario is represented with one point in each series.*

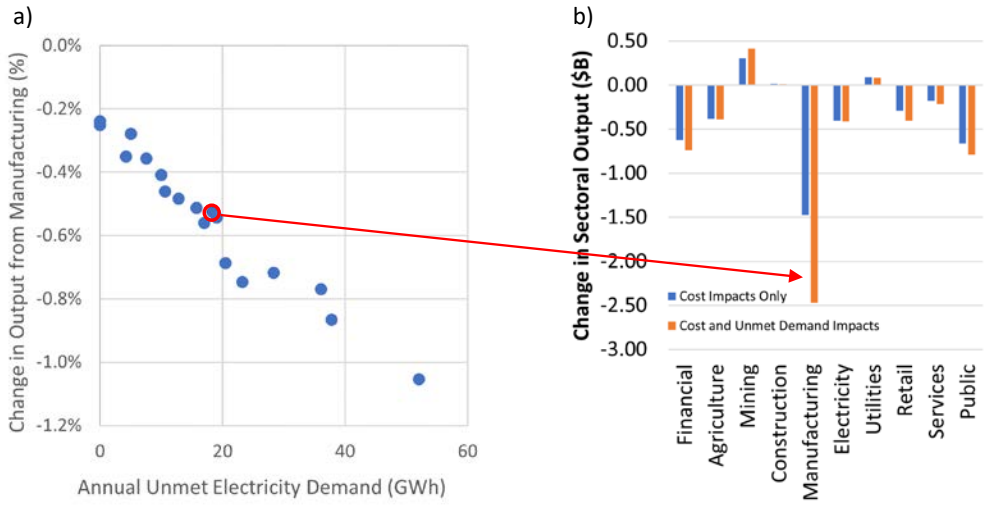

***Figure 3**: a) Reduction in output (%) from Manufacturing Sector for the simulated climate scenarios; b) the reduction in output ($B) from all production sectors from one scenario (GFDL-CM3, year 2089).*

To measure the relative importance of higher electricity costs versus unmet electricity demand to total economic loss from higher water temperatures, we compare the results from two versions of the model: 1) one that represents impacts from both higher electricity cost and unmet electricity demand, and 2) one that represents only the impact of higher electricity cost. The consumption loss due to unmet electricity demand is significantly larger than the consumption loss due to higher electricity cost (**Figure 2)** and constitutes the primary driver of impacts on the broader

economy. In particular, for scenarios with fewer outages and shorter durations, nearly all the impact is from the productivity loss from the interruptions. For the scenarios with the greatest magnitude and duration of outages, the price effects alone account for only one third of the impact on the economy. Quantitative estimates of the losses to industry from insufficient electricity supply emphasize that the damages depend on when the unmet demand occurs and how long it goes unmet for each event; i.e., timing is a critical factor. It is not possible to quantify these losses without a chronological hourly analytical framework.

The increase in electricity cost and the decrease in productivity due to unmet electricity demand have differential impacts across the other sectors of the economy. This is a result of differences in the relative dependence on electricity vs. other inputs to production in each sector and variation in sectoral damages costs from electricity outage events. **Figure 3b** shows the change in output ($B) in all sectors for one scenario (GFDL-CM3, year 2089). The largest reductions in terms of economic value occur in the manufacturing sector. We also show the resulting change in manufacturing output (%) in all simulated scenarios (**Figure 3a**). The productivity loss for all sectors for the 18 water temperature scenarios are provided in Table S4 in the SI. Note that we do not include an economic value on unmet residential demand.

Feedbacks between economy and power system

The impacts presented above from climate forcing to water temperatures to capacity outages to electricity costs and unmet demands represent the potential impacts in the absence of an economic response. Economic agents respond to changes in prices and quantities to modify their behavior, and this response must also be represented. Demand for electricity will fall in response to higher electricity prices, which encourage substitution away from electricity use. Demand for electricity will also fall because the economy has contracted due to the economic losses from higher electricity costs and productivity losses due to unmet electricity demand. Feeding these adjustments in electricity demand back to the PSM will reduce the estimated impacts because less generation will be required to meet the lower demand level.

We iterate between the PSM and the REM after estimating the impacts from the higher water temperatures to capture this demand feedback. Specifically, the higher water temperatures from the WBM result in increased electricity costs and unmet demand in the PSM, which leads to lower demand for electricity in the REM. This lower electricity demand from the REM is fed back to the PSM, and the resulting electricity cost and unmet demand impacts will be lower than the previous iteration. The adjusted electricity costs and unmet demand estimates from PSM are then fed back to the REM, which may further adjust the electricity demand. The two models iterate until changes between the two models reach zero.

The results from the final iteration, after equilibrium is achieved, is a useful indication of the likely impacts from the original water temperature scenario because it accounts for the economic response feedbacks. The dampening of the impacts by economic adjustment is illustrated in **Figure 4**, which presents the range of impacts before and after economic adjustments in the form of box-and-whisker plots. Economic substitution is most effective at reducing the cost of electricity (**Figure 4a**). In response to the higher cost, production shifts to other inputs and the

economy contracts, leading to a reduction in the demand for electricity. The reduction in unmet demand and in consumption loss after economic adjustments are not as large as the initial estimate before adjustment. Note that we present the impact on average electricity cost without economic adjustment, which would never be observed in reality, to illustrate the importance of considering the economic response. Our range of cost increases before economic adjustment is comparable to previous studies[11,12] that do not include economic responses. Our results suggest that such studies are inherently biased towards higher cost increases than would be realized.

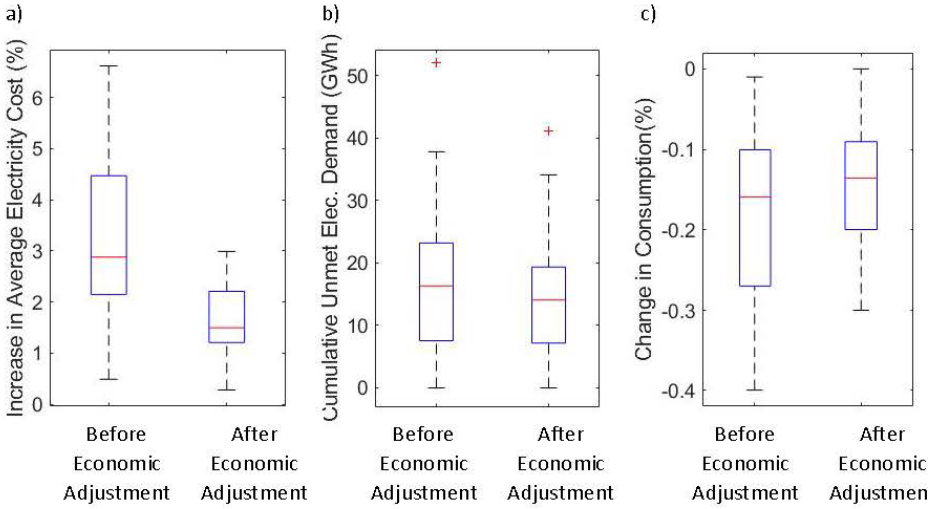

Figure 4: *Impacts from 18 annual hydrological samples before and after economic adjustment a) percentage increase in the average electricity cost, b) cumulative unmet electricity demand, and c) the net consumption loss.*

System stress in coupled networks

For any given external shock, the interconnected networks in the water-power-economic system mitigate the impact by providing redundancy and transferring the impact spatially. As an illustration, **Figure 5** shows the geographic relationships between impacts in the WECC region from a given week in one of the WBM scenarios (GFDL, year 2097; week 29). The generators that are unavailable because the water temperature threshold is exceeded are primarily located in Southern California, Southern Nevada, Arizona, and New Mexico (blue circles in **Figure 5**). When these generators are unavailable, other generators elsewhere in the network must compensate. This shift in generation causes congestion on some of the transmission lines; i.e., the power flows on those lines are at their maximum capacity (red lines in **Figure 5**). Congestion causes the cost of electricity to increase in some locations, because lower cost generation is unable to be transported to where the demand is, and in some cases may also lead to unmet demand at other locations (teleconnections). In this example, the net effect of the generation outages is that some portion of electricity demand in Colorado and some in Arizona cannot be met for some hours of the week (red circles in **Figure 5**). The episodes of power outages in turn disrupt economic activity, reducing productivity and increasing costs. The spatial patterns of generator outages are consistent across the most extreme water temperature scenarios (Table S5 in the SI), and similarly the locations of unmet electricity demand mainly occur in Colorado and

Arizona. The locations where the unmet demand occurs is driven by the bottlenecks in the transmission network and the particular spatial patterns of electricity demand and renewable generation in this set of experiments. In general, the locations of generator outages from increased water temperatures are distinct from where the impacts on consumers will be experienced.

Although consistent across water temperature scenarios, changes in the locations of generators through retirements and additions and changes in the transmission network will change the location where impacts occur even for the same water temperature scenario. We demonstrate the sensitivity of results to these assumptions using three illustrative future generation scenarios: 1) in which coal generators are retired in mostly southern states in WECC, 2) in which coal generators are retired in mostly northern states in WECC, and 3) in which coal and natural gas steam generators are retired in California. In all three scenarios, wind and solar capacity was added to replace the retired capacity. The same water temperature scenario illustrated in Figure 5 (GFDL 2097) was simulated for the three alternative generation scenarios.

For case 1, similar locations experience unmet demand, but the affected transmission lines are in different locations. For case 2, unmet demand is observed in southern CO, southern UT and some locations in Canada. For case 3, significant retirements in California shift the location of unmet demand from Colorado to Arizona. The detailed assumptions and results are presented in the SI (see Figure S6). These three scenarios of future generation types and locations are neither the only possible nor the most likely futures. A rigorous and thorough exploration of future generation and transmission changes requires the addition of a generation capacity expansion component to our modeling framework and is beyond the scope of this current study.

Discussion

Our analysis of the impacts of a range of climate forcing patterns on the coupled water-power-economic system has demonstrated that higher water temperatures can lead to a causal chain of events from electric power generators offline because of cooling water intake temperature limits to higher electricity costs and unmet electricity demand to economic adjustment to productivity reductions in electricity using sectors. The net consumption loss can be as much as 0.3% annually across the broader regional economy, with up to a 3% increase in the average cost of electricity, and more than a 1% loss of production from regional manufacturing. The key insights are that many climate patterns that result in generator outages from higher water temperatures do not result in any significant impacts (thresholds), that most of the economic impacts result from electricity demand that cannot be met at specific times and locations (timing), and that these unmet demand events may occur at geographically distant locations from the generator outages (teleconnections).

The results underscore the importance of accounting for feedbacks between overlapping and interacting system networks. Importantly, this type of coupled model approach allows investigators to retain the spatial, temporal, and sectoral richness represented in each of these individual models that would be unachievable in one comprehensive model where detail is

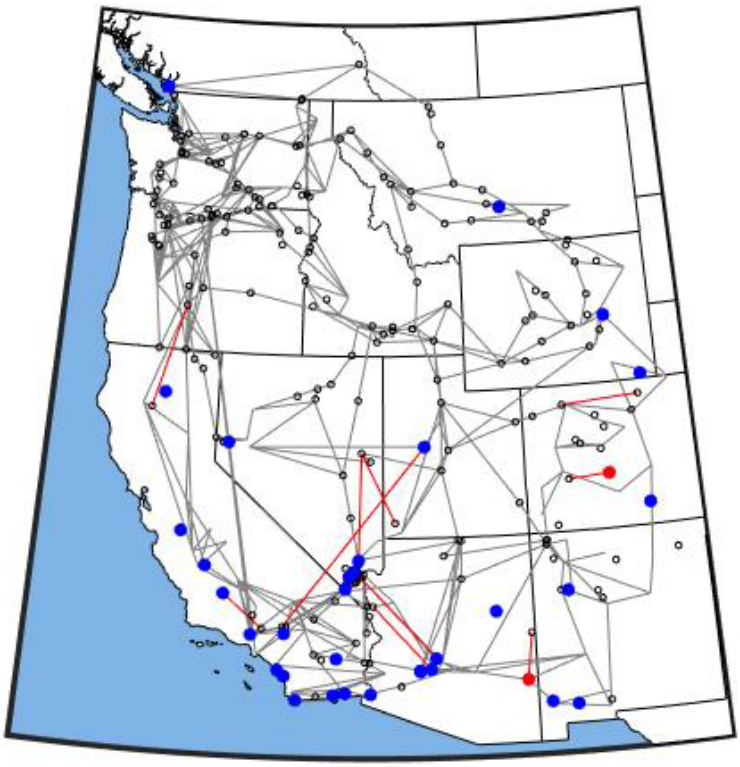

Figure 5*: Geographic distribution of impacts (GFDL, 2097, week 29). Blue circles indicate the geographic locations of generators that are unavailable for at least one day of this week because of the water temperature restrictions, red lines indicate the transmission lines that experience congestion, and red circles indicate geographic locations that exhibit unmet electricity demand.*

usually sacrificed for computational tractability. In particular, the chronological hourly resolution of the power system is critical to be able to represent discrete events of intermittent power disruptions, the largest factor affecting economic cost. Similarly, sectoral detail allows us to differentiate between those industries that are hardest hit by these disruptions and those that are not, providing further evidence that impacts are not likely to be uniform across space, time, and sector.

For public and private sector organizations focused on increasing resilience to natural stressors from weather and climate, our analysis reinforces the importance of institutions for managing regional interdependent infrastructures. Lack of cooling water may prevent generators in Southern California or Arizona from operating, but the consequence could be felt elsewhere such as in Colorado. Regional coordination from organizations such as WECC or the Western Governors Association will be required to identify network vulnerabilities that can transmit impacts spatially and develop reinforcements that do not cause new unintended problems.

The analytical framework presented here is applicable to other shocks and other impact pathways. Other sources of system stress include extreme cold, storms, floods, and wildfires. Changes in hydrological flows and temperatures can affect not only thermal power generators but would have different impacts on hydroelectric generation and would affect electricity demand. The multi-sector model approach is necessary to represent the causal linkages for each

of these stressors. The real value of the proposed coupled modeling approach is that it can be used to understand a range of unexpected impacts of climate change due to feedbacks between connected subsystems.

Importantly, future work must also rigorously investigate how potential adaptations will change the risk profile. Any investments in the power or water infrastructure will modify the network structure and flows, which may alter how external shocks are dampened or amplified and transferred geographically. A rigorous assessment of the tradeoffs between these alternative strategies will require advances in computational methods for managing high-dimensional data. Similarly, future work should include rigorous uncertainty characterization and quantification addressing both the uncertainty in the occurrence of extreme water stress events and the uncertainty in the impact when these hydrological conditions occur. The authors hope that the analysis presented here will motivate and accelerate this agenda in the larger research community.

Methods

Our coupled model framework consists of the Water Balance Model (WBM), a spatially distributed hydrological model, the Power System Model (PSM) with chronological hourly resolution, and the Regional Economic Model (REM), a state-level computable general equilibrium model. WBM is a process-based, gridded model that simulates both the vertical exchange of water, and the horizontal transport of water through runoff and the river network, developed at the University of New Hampshire[13,14] and includes estimated river temperature calculations.[15] The results in this paper are based on the RCP8.5 scenarios from GFDL-CM3 and from CCSM4. WBM uses downscaled climate fields to drive simulations 2006-2099 with daily time-steps. The gridded daily hydrological conditions from each simulated year in WBM constitutes one scenario. We treat the annual samples of daily hydrological conditions from the WBM results for 2041-2099 from GFDL-CM3 and CCSM4 as 118 independent scenarios of plausible future hydrological patterns for the purposes of this study. Detailed analysis focuses on a subset of 18 scenarios from this larger set selected using importance sampling (details in SI.3).

All thermal power plants in the WECC system that require water for cooling are mapped to specific grid cells in WBM. For the impacts on electric power supply, we assume the U.S. federal standard water temperature threshold of 32 °C,[2,8,9] above which generators requiring water for cooling at those locations are not available on that day. We only consider generators offline above this threshold and do not explicitly model partial capacity derating for water temperatures below this threshold; our estimates are therefore conservative in terms of likely available capacity. We then solve a one-year simulation for the hourly dispatch of generators to meet demand in the PSM, a model of the WECC system that represents the high-voltage transmission network (consisting of 312 locations and 654 transmission lines) developed by Hobbs and colleagues at Johns Hopkins University[16,17,18,19] and intertemporal operational constraints of generators, as well as a given scenario of hourly availability of all generators over the year based on the WBM input.

The resulting cost of electricity and hourly patterns of unmet electricity demand (if any) provide input to the REM, a static inter-regional computable general equilibrium (CGE) model of the United States. The REM is based on the modeling framework of Rausch and Rutherford,[20] which calibrates the model to the IMPLAN U.S. state-level accounts. Finally, to represent the economic adjustment to the initially higher electricity costs from the external stressor, we iterate between the PSM and REM using the coupling methodology of Böhringer and Rutherford[21] to find the equilibrium reduction in electricity demand. Impacts of each scenario are presented as the final equilibrium results for reductions in regional consumption and in sectoral output from the REM. Detailed descriptions of the methods, including all models and data, are provided in the Supplemental Information (SI) available online.

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Author contributions

M.W., K.F-V., and R.L. conceived and designed the experiments. M.W., K.F-V., V.K., and R.L. analyzed the data. M.W., K.F-V., J.P., V.K. and R.L. developed the models and coordinated the model experiments. M.W., K.F-V., and R.L. wrote the paper.

Competing Interests

The authors declare no competing interests.

Additional Information

Supplementary information is available for this paper.

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